SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

Jennifer R. Hasbrouck
Attorney
jennifer.hasbrouck@sce.com

August 9, 2002

Docket Clerk
California Public Utilities Commission
505 Van Ness Avenue
San Francisco, California 94102

RE: R.02-06-001 – Advanced Metering, Demand Response and Dynamic Pricing OIR

Dear Docket Clerk:

Enclosed for filing with the Commission are the original and five copies of the **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REPORT ON EXISTING AND PLANNED DEMAND RESPONSE AND PRICING OPTIONS** in the above-referenced proceeding.

We request that a copy of this document be file-stamped and returned for our records. A self-addressed, stamped envelope is enclosed for your convenience.

Your courtesy in this matter is appreciated.

Very truly yours,

Jennifer Hasbrouck

Jennifer R. Hasbrouck

JRH:scp:LW022200019
Enclosures

cc: All Parties of Record in R.02-06-001
(U 338-E)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.	R.02-06-001 (Filed June 6, 2002)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REPORT ON EXISTING AND PLANNED DEMAND RESPONSE AND PRICING OPTIONS

MICHAEL D. MONTOYA
JENNIFER R. HASBROUCK

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1040
Facsimile: (626) 302-2050
E-mail: jennifer.hasbrouck@sce.com

Dated: August 9, 2002

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.	R.02-06-001 (Filed June 6, 2002)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REPORT ON EXISTING AND PLANNED DEMAND RESPONSE AND PRICING OPTIONS

I.

INTRODUCTION

In accordance with the California Public Utilities Commission's ("Commission") directives as set forth in the Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing dated June 6, 2002 (the "OIR"), respondent Southern California Edison Company ("SCE") hereby submits this report describing SCE's existing and planned efforts concerning demand response and pricing efforts. As directed by the Commission in the OIR, this information is presented to help facilitate the Commission's investigation into where gaps may exist in the ongoing and planned efforts of the utilities and other agencies such as the California Energy Commission ("CEC") and the California Power Authority ("CPA").

II.

BACKGROUND

A. Purpose of this Report

In the OIR, the Commission cites its intention to consider a strategic approach towards the orderly development of demand responsiveness capability in the California electric market. Toward this end, the Commission has designed its preferred approach which involves conducting a review of existing and planned demand response efforts in California to identify gaps in current efforts and then initiating further discussion as to how such gaps might be filled in order to maximize demand response resources. To facilitate the Commission's investigation into identifying potential gaps, the Commission directed all the parties in this proceeding to submit a brief description of their existing and planned demand response and pricing programs.

This report provides a brief description of SCE's existing and planned efforts for its demand response programs and pricing options available for its large customers, medium and small business customers, and residential customers. This filing also identifies some issues that may be discussed in a workshop setting when considering options to address any potential gaps that may exist.

B. Background on the Focus of this Report

In the OIR, the Commission identified three categories of demand response efforts, including short-term emergency options, flexible dispatch options, and permanent options. The Commission stated that its intention in this Rulemaking will be to focus on demand response efforts that are considered to be "flexible and dispatchable" in nature. The Commission cited time-of-use ("TOU") pricing, real-time pricing, smart thermostats, demand bidding and energy management control systems as the types of efforts that are included within the scope of this proceeding. In its discussion of program strategies for customer demand reduction, the Commission categorized interruptible and direct load control programs as "emergency" strategies that are generally outside the scope of the proceeding.

Despite this initial attempt to narrow the scope of this proceeding, the OIR did cite to some existing programs, such as Santa Clara County's base interruptible program, as examples of existing programs that would be considered in its strategic approach, even though technically an interruptible program might be categorized as an "emergency" effort. In order to provide a comprehensive list of existing demand response efforts for the Commission's consideration, SCE is including information in this report on its "emergency" efforts (interruptible and direct load control programs) and its "flexible dispatch" efforts on both current and planned demand response programs, dynamic/TOU pricing, and supporting infrastructure. Providing information on these programs will also be useful to the Commission because they provide valuable information on customer response and acceptance of existing "emergency" programs. SCE believes that these programs need to be viewed along side "flexible dispatch" programs as an integrated portfolio of demand response program options that are available to customers. SCE's current demand response programs offer nearly 1,000 MW of curtailable load. Major energy efficiency initiatives and related programs are considered to be outside the scope of this proceeding.

III.

DESCRIPTION OF EXISTING AND PLANNED DEMAND RESPONSE AND PRICING PROGRAMS

In accordance with the directives set forth in the OIR, SCE provides a brief description of its existing and planned demand response programs and pricing options for large customers, medium and small business, and residential customers. For purposes of this report, SCE considers "Large Customers" to be accounts with registered demand equal to or in excess of 200 kW, although some programs may only be available to customers with demands of 500 kW or greater. Conversely, "Small or Medium Commercial Customers" are considered to be commercial customers with demands less than 200 kW.

The OIR asked specifically that for each existing or planned demand response or pricing effort identified, the parties provide the following information: (1) description of the target customer segment(s); (2) type of strategy; (3) parties involved; (4) hardware and/or software requirements; (5) resources delivered or planned; (6) cost; (7) funding source; and (8) status. This information is discussed in detail in this report, but is summarized in Table III-1 below:

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
Demand Bidding	Large Commercial & Industrial (>500 kW) Small & Medium Commercial (>100 kW)	Flexible	SCE, ISO	Internet Web Site Curtailment Event Management system (software) IDR	15.9 (min. bid) 212.0 (max. bid)	Incentive Admin/Opns Total	N/A	35 c/kWh $9 /kW NA	ILPMA ILPMA	Operational

---

1 Incentive costs for SCE's traditional interruptible programs (I-6, ACCP-Base and AP-I) are derived from 2001 actual payments to participants and estimated available interruptible loads during that period. ACCP-Enhanced incentives are twice those derived for ACCP-Base. BIP incentive is the monthly credit ($7/kW) annualized. I-6 incentives are adjusted to exclude the impact of a bill limiter rate subsidy. SLRP and DBP incentives reflect the tariff payment amount per kWh. Administration and operations costs for all interruptible programs are derived from 2002 booked amounts through June 30 and annualized.

2 Funding sources are as follows:

DSM C'over: D. 97-12-103 authorized SCE to use the DSM carryover balance from the DSM Balancing Account to fund pre-1998 commitments such as the I-6, ACCP-Base and AP-I load control programs, with the expectation that these programs would require funding only through March 31, 2002. However, D.01-04-006 extended the programs through 2002 and subsequently D.02-04-060 extended the programs through the conclusion of SCE's 2003 GRC. SCE expects to exhaust the Demand Side Management carryover funds in 2002. At that point SCE will record the administrative and operations cost of these programs in the ILPMA for the remainder of 2002. SCE has requested recovery of all program costs in base rates for 2003 and beyond in its 2003 GRC.

ILPMA: The Interruptible Load Program Memorandum Account was authorized by the Commission in D.01-04-006 to allow SCE to record the costs of new programs that exceed that authorized in base rates. SCE is allowed to recover these costs subject to a reasonableness review held in the Annual Earnings Assessment Proceeding.

Base Rates: Costs funded in base rates were authorized in the 1995 GRC. The incentives for the traditional interruptible programs as well as a portion of administrative and operations expenses of these programs are funded in base rates.

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
SLRP	Large Commercial & Industrial (>500 kW) Small & Medium Commercial (>100 kW)	Flexible	SCE	IDR	4.0	Incentive Admin/Opns Total	N/A	10¢/kWh $12/kW NA	ILPMA ILPMA	Operational
Interruptible Load Program (Schedule I-6)	Large Commercial & Industrial (>500 kW)	Emergency	SCE, ISO	Radio Comm. System; RTU and dedicated telephone at customer site; Auto. Notification System; IDR	591.0	Incentive Admin/Opns Total	N/A	$112 $ 2 $114	Base Rates DSM C'over	Operational (closed to new customers)
BIP	Large Commercial & Industrial (>500 kW)	Emergency	SCE, ISO	Dedicated telephone at customer site; IDR; Auto notification system	27.0	Incentive Admin/Opns Total	N/A	$84 $ 7 $91	ILPMA ILPMA	Operational
OBMC	Large Commercial & Industrial (>500 kW)	Emergency	SCE, ISO	Automated Notification System; IDR; Circuit Metering (if necessary)	9.3 (5%) 18.5(10%) 27.8(15%)	Incentive Admin/Opns Total	N/A	$ 0 $16* $16 *based on 5% level	ILPMA ILPMA	Operational
AP-I	Agriculture & Pumping	Emergency	SCE, ISO	Radio comm. system; Load Control device at customer site; Auto-notification system	25.5 (on-peak) 41.5 (off-peak)	Incentive Admin/Opns Total	N/A	$50 $ 4 $54	Base Rates DSM C'over	Operational

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
A/C Cycling-Base Program	Large Commercial & Industrial (>500 kW)	Emergency	SCE, ISO	Radio comm. system; Load control device at customer site	37.2	Incentive Admin/Opns Total	N/A	$52 $ 3 $55	Base Rates DSM C'over	Operational
	Small & Medium Commercial (<500 kW)					Load Control Device&Instal	$153	-	DSM C'over	

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
A/C Cycling: Enhanced Program	Large Commercial & Industrial (>500 kW) Small & Medium Commercial (<500 kW)	Emergency	SCE, ISO	Radio comm. System; Load Control device at customer site	1.3	Incentive Admin/Opns Total Load Control Device&Instal	N/A $153	$104 $ 3 $107 -	ILPMA ILPMA ILMPA	Operational
RTEM	Large Commercial & Industrial (>200 kW)	TOU Pricing (Infrastructure)	SCE, CEC	IDR Meter with pulse board, Various Meter Communications Devices Include: Two-way Pager, Internal Phone Modem or RS232 Board for use with Netcomm Wireless System Software Applications: M32 & MV-90 Web-Based Customer Interface Communication System	N/A	(Annual $000) One-Time Costs: Meter Hardware Comm. Sys. Meter Installation Customer Data Comm. End-User Education Total One-Time Costs Total 2001 Ongoing Costs Total 2002 Ongoing Costs		($000) $11,937 $2,737 $3,139 $8,234 $446 $26,493 $4,873 $4,368	ABX 1-29 & SBX 1-5; RTEM Memo Account[3]	Operational

3 ABX1 29 and SBX1 5 authorized funding by the CEC to the utilities for real-time meters and related infrastructure. The RTEM Memorandum Account tracks incremental costs associated with installation and operation of RTEM equipment that exceeds funding by the CEC.

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
Rate Schedules: RTP-2 RTP-2-1 TOU-8 TOU-PA's TOU-8-SOP TOU-8-SOP-I TOU-PA-SOP TOU-GS GS-2-TOU	Large Commercial (>200 kW)	Pricing Options	SCE	IDR Meter	N/A	N/A	N/A	N/A	Base Rates	Operational
A/C Cycling: Base Program	Residential	Emergency	SCE, ISO	Radio comm. System; Load control device at customer site	199.2	Incentive Admin/Opns Total Load Control Device&Instal	N/A $153	$50 $ 3 $53 -	Base Rates DSM C'over DSM C'over	Operational

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
A/C Cycling: Enhanced Program	Residential	Emergency	SCE, ISO	Radio comm. System; Load control device at customer site	9.6	Incentive Admin/Opns Total Load Control Device&Instal	N/A $153	$100 $ 3 $103 -	ILPMA ILPMA ILPMA	Operational
Smart Thermostat Pilot	Small Commercial (>200kW)	Flexible	SCE, CEC	Programmable thermostat; Internet Website; 2-way pager communications	4.0 (at full build-out)	Incentive Auth.Annual Budget[4]	$300 $5.94 million	NA	Demand Reduction & Self-Gen. Incremental Costs Balancing Account [5]	Operational
Rate Schedules: TOU-GS TOU-GS-SOP TOU-PA-SOP TOU-EV TOU-PA's TOU-D1 TOU-D2	Small Commercial (<200 kW) Residential	Pricing Options	SCE	TOU Meter	N/A	N/A	N/A	N/A	Base Rates	Operational

4 Smart Thermostat pilot was authorized in D.01-03-073, with an annual budget of $5,940,000, consisting of $1,188,000 for contract administration, marketing, regulatory reporting and program evaluation and $4,752,000 for hardware, software, communications, and customer incentives.

5 The Demand Reduction and Self-Generation Incremental Costs Balancing Account records incremental costs and benefits associated with the Smart Thermostat Pilot Program and the Self-Generation Pilot Program. Disposition of amounts recorded will be determined in the annual Revenue Adjustment Proceeding or other proceeding authorized by the Commission.

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
Rate Schedule RTP/TOU	Large Commercial (>200 kW)	Pricing Option	SCE	RTEM Infrastructure	N/A	N/A	N/A	N/A	N/A	Planned
Critical Peak Pricing Pilot	Small Commercial (<200kW)	Pricing Pilot	SCE, CEC	IDR Smart Thermostat Customer Notification system	N/A	N/A	N/A	N/A	N/A	Planned

A. Description of SCE's Existing Efforts for Demand Response Programs and Pricing Options

1. Description of Existing Demand Response Programs and Pricing Options Available to Large Customers

a) Demand Response Programs

SCE offers a number of existing demand response pricing, programs and infrastructure available to Large Customers, including the following:

(1) Demand Bidding Program

The Demand Bidding Program ("DBP") is a reliability-based demand-response program that offers customers a payment or credit on their bill when they curtail load at critical times as determined by the California Independent System Operator ("ISO").[6] During such critical times, a customer may bid for specified load reductions in exchange for being paid $0.35 per kWh if the bid is accepted and executed.[7] Customers may submit bids between 8:00 a.m. and 8:00 p.m. on weekdays. Participants must submit bids to reduce load for at least two consecutive hours, but may vary the size of the bid by hour. There are no penalties associated

---

[6] On July 17, 2002, in D.02-07-035, the Commission modified the terms of the DBP, transforming the DPB from a price mitigation program triggered by the California Department of Water Resources to a reliability program triggered by the ISO. The ISO will trigger a day-ahead DBP event when system reserves are anticipated to fall below 7% in the next 24 hours. The ISO may also trigger a day-of event when system operating reserves are forecast at 7% or below on an hour-ahead basis. The ISO may determine the length of the DBP event and limit the total amount of load reduction requested.

[7] The amount of a participant's load reduction is determined by comparing the hourly demands to the corresponding 10-day rolling average demand.

with this program.[8] DBP participants may be enrolled in other demand response programs such as I-6, BIP or ACCP, but they will not receive any payments for DBP during periods when load reductions under the other programs are in effect.

Since this program's recent redesign from a market-driven to a reliability-based program, the ISO has not yet triggered an event. Thus, at this time, SCE has no actual performance data from which to make meaningful estimates of projected load reductions. The DBP is available to all customers whose demand is equal to or greater than 100 kW.

As of June 30, 2002, SCE has enrolled 98 customers with a total of 135 service accounts. The maximum potential bid amount is 212 MW, while the minimum potential bid amount, assuming all customers bid their minimum requirement under the terms of the program, is 16 MW.

SCE utilizes an Internet-based application that leverages SCE's RTEM infrastructure (see description of RTEM below) for the Demand Bidding Program's customer notification, bidding, and operations. The Internet-based application, designated "SCE Curtailment Manager," is currently available only to DBP participants; however, SCE plans to extend certain capabilities of the application to other demand response programs, as appropriate.

SCE Curtailment Manager supports program participants as well as SCE's program operations and delivery. For program participants, the application provides notice of activated curtailment events, presents program information and incentives as well as historical, rolling averages, and target loads. It also provides the interface for program participants to submit curtailment bids as well as to

---

[8] Non-compliance on three consecutive occasions will result in the participant being excluded from bidding for the subsequent two DBP events.

monitor performance in near real time. Finally, it provides program participants with their estimated earned incentive. For SCE, the application allows rapid deployment of new or revised curtailment programs and complete program operations support, including event and customer performance reporting.

(2) Scheduled Load Reduction Program

SCE's Scheduled Load Reduction Program ("SLRP") is a load reduction program that was mandated by the California State Legislature in Senate Bill X1 5. SLRP is exclusively a summer program, effective only from June 1 through September 30. Participating SCE customers receive a payment in the form of a bill credit of $0.10 per kWh when they agree to curtail load at pre-scheduled time periods. This program is available to SCE customers with demands of 100 kW and above. A participating customer may choose up to three of the following time periods a week during which they will curtail their usage: 8:00 a.m. to 12:00 p.m.; 12:00 p.m. to 4:00 p.m.; and 4:00 p.m. to 8:00 p.m. The customer may not choose the same time period more than twice a week. The SLRP program is in effect Monday through Friday, excluding holidays. There are no penalties associated with this program.[9]

As of June 30, 2002, SCE has enrolled 17 participants. Currently the maximum load reduction scheduled is 4.0 MW for most of the allowed hours on Mondays. On Fridays, the scheduled load reduction is on average about 1.5 MWs. For the balance of the weekdays, the load reductions range from zero (for eight hours) to 230 kW. For most of the week, current SLRP participants do not offer the ISO significant load curtailment capabilities when it may actually be needed to

---

[9] If a customer fails to curtail usage five times, the customer will be removed from the program.

maintain system reliability during an emergency. In SCE's Phase 2 General Rate Case ("GRC"), SCE is considering a proposal to terminate the SLRP.

(3) Commercial Interruptible Load Program

The I-6 Interruptible Load Program is available to Large Commercial and Industrial Customers whose demand exceeds 500 kW and who agree to curtail their electric demand during a system capacity shortage or other emergency.

Under the program, a participating customer receives a discounted demand and energy rate for reducing load when requested by SCE. The discounted demand rate is applied to the amount of interruptible load contributed by the customer, which is defined by the excess of the customer's measured demand over its Firm Service Level ("FSL").[10] The discounted energy rate is applied to the kWhs that exceed what the customer would consume at its FSL over the time period to which the energy rate applies. The demand and energy discounts are generally greatest during the summer months.

A customer is called upon to reduce load to its FSL when SCE is notified by the ISO that a Stage 2 emergency exists and that non-firm load reductions are required. SCE then notifies the customer, who has thirty minutes to reduce the customer's load to the FSL. Customers may be asked to reduce load for a period not to exceed six hours per event, with a maximum of four events per calendar week, 40 hours per month, and 150 hours or 25 events per year. Customers may increase or decrease their FSL, or elect to terminate participation in the program during an annual 30-day window, beginning November 1 of each year.

---

[10] The FSL is that level of demand that the customer agrees not to exceed during an interruptible event.

For each period of interruption during which the customer fails to interrupt (and hence consumes energy in excess of the customer's FSL), an applicable excess energy charge is added to the customer's bill based on the amount of excess energy used. Excess energy is the number of kWhs consumed during each period of interruption that exceed the product of the firm service level kW multiplied by the total number of hours of interruptions within the time period.

Customers are notified of an interruption through the use of a Remote Terminal Unit ("RTU") and/or back-up automated telephone communications. The RTU initiates an alarm at the customer's site to indicate that the emergency is in effect and that the participant has thirty minutes to reduce load. If the dedicated back-up telephone system is used, the customer is notified via telephone of the emergency and likewise has thirty minutes to reduce load. The participant may also connect load-shedding equipment to the RTU to automatically open circuits to the customer's equipment.

As of June 30, 2002, 571 service accounts are enrolled in the I-6 program, with a load reduction potential of approximately 591 MWs. The tariffs governing the program have been closed to new customers, with the exception of customers new to SCE's service territory and to existing customers adding new load since November 26, 1996. In SCE's Phase 2 GRC, SCE will be proposing to terminate the I-6 program and transfer participating customers to its Base Interruptible Program, described below.

(4) Base Interruptible Program

Like the I-6 program, the Commission-mandated Base Interruptible Program ("BIP") is a discounted rate option available to customers with maximum demand of 500 KW or greater who agree to curtail their electric demand during a system capacity shortage or other emergency. However, unlike the I-6 program, which has no minimum load reduction requirements, BIP participants must be able to reduce load by at least 15% of their annual maximum demand or a minimum of 100 kW. BIP is currently open to all eligible customers. In its Phase 2 GRC, SCE will be proposing to modify the eligibility requirements so that customers with maximum demands as low as 200 kW may participate in BIP.

A customer participating in the BIP program is paid a reservation fee for demand that it agrees to reduce when requested by SCE. The reservation fee is in the form of a bill credit applied only to the demand component of the interruptible load. Interruptible demand for rate discounting is the excess of the customer's average peak-period (mid-peak during the winter season) demand over its FSL.

A BIP participant is called upon to reduce load to its FSL when SCE is notified by the ISO that a Stage 2 emergency exists and that non-firm load reductions are required. BIP participants are notified by telephone through an automated notification system. As is the case for I-6 participants, a BIP participant has thirty minutes from notification to reduce load to its FSL.

The number and frequency of times that SCE may ask a BIP participant to reduce load are slightly lower than those required for the I-6 program. BIP participants may be asked to reduce load for a period not to exceed four hours per event per day, with a maximum of 10 events per month or 120 hours per year. Customers may increase or decrease their FSL, or elect to terminate participation in the program during an annual 30-day window, beginning November 1 of each year, subject to the normal tariff restrictions requiring customers to remain on a rate for 12 months. As is the case with participants in the I-6 program, a BIP participant is also subject to penalties for not reducing load when requested to do so.

As of June 30, 2002 there are 36 participants in BIP with an estimated interruptible load of 27 MWs.

(5) Optional Binding Mandatory Curtailment Program

The Optional Binding Mandatory Curtailment ("OBMC") program exempts customers from rotating outages in exchange for partial load curtailment of their entire circuit during every rotating outage. Customers are required to file an OBMC plan that is acceptable to SCE prior to participation in the program. Customers are responsible for the installation and cost of communications and metering equipment required to participate in the program.

To participate, a minimum of 15 percent of the entire circuit load must be available for curtailment during every rotating outage. If any one customer does not have enough curtailable load to provide the 15 percent minimum requirement on their own, customers on the same circuit may submit one OBMC plan outlining how they can provide the 15 percent minimum requirement by combining total curtailable circuit load. OBMC customers are eligible to participate in other capacity interruptible programs, such as the interruptible I-6 program and the BIP program, subject to certain restrictions, as well as the DBP. Customers who fail to reduce load when requested are subject to penalties.

Since the program's inception, no OBMC events have occurred. As of June 30, 2002, there are 14 OBMC customer plans in effect, with a circuit load of 27.8 MW at the 15% curtailment level.

(6) Agricultural and Pumping Interruptible Program

The Agricultural and Pumping Interruptible Program ("AP-I") is applicable to those customers served under an Agricultural and Pumping rate schedule that elect to provide interruptible load automatically. Qualifying customers must have a measured demand of 50 kW or greater, or a connected load of 50 horsepower or greater. The customer's interruptible load is the total load served under the regularly applicable rate schedule. No firm service level applies. This program is currently open to new customers, but it may not be available in certain areas where communication-signaling equipment has not been installed or signal strength is inadequate to activate or deactivate an interruption.

Load is controlled through a VHF-FM radio-controlled switch. These devices are one-way receivers that provide no signal receipt verification. An end-of-interruptible-period signal is transmitted to the control device and customers must manually restart electrical equipment at the end of the interruptible period. Some customers have requested and paid for remote interruption signal monitors to know when an interruption occurs, and when they may restart their pump motors. Other customers without a remote monitor must periodically inspect their equipment in the field.

Upon receipt of an ISO Stage 2 emergency declaration, SCE may activate the AP-I program. To join the program, customers pay a one-time charge for the cost of the control and monitoring equipment. AP-I customers receive a discounted rate for agreeing to reduce load when requested by SCE.

Customers may elect to terminate participation in the AP-I program during an annual 30-day window, beginning November 1 of each year. As of June 30, 2002, a total of 375 customers are enrolled in this program, representing a potential net peak load reduction of 26 MWs.

(7) Air Conditioner Cycling Program (Base and Enhanced)

SCE offers both Residential and Non-Residential Base and Enhanced Air Conditioner Cycling ("A/C Cycling") programs to all customer segments. The A/C Cycling programs are applicable to customers serviced under either SCE's Residential or General Service rate schedules. Under the provisions of these programs, customers agree to installation of an automatic control device that is installed, operated, and maintained by SCE at the customer's premises. The device is radio controlled and can cycle a customer's air conditioner off and on. SCE activates the cycling signals when directed by the ISO to curtail specific amounts of load. The A/C Cycling Program utilizes the same communications system, including transmitters and towers that are used for the I-6 and AP-I programs.

Participants may select an air conditioner cycling strategy to determine the percentage of time that the air conditioner is disconnected during an interruptible period. The cycling strategy options for residential customers are 50%, 67% or 100%. The cycling strategy options for non-residential customers are 30%, 40%, 50% or 100%. A participant may change to a lower cycling strategy at no charge during its first 12 months participation in an A/C Cycling program, and at a cost of $30 thereafter.

The A/C Cycling Base program is limited to 15 cycling periods per year. Under the A/C Cycling Enhanced Program, there is no limit to the number of interruptions that may occur. The interruption duration per occurrence for all A/C Cycling programs are limited to no more than six hours at a time. Interruption periods may occur during the summer season beginning at 12:00 a.m. on the first Sunday in June, and ending at 12:00 a.m. on the first Sunday in October. Participating A/C Cycling customers receive credits on their bill during the summer season months regardless of whether A/C cycling occurred. The credits for the A/C Cycling Enhanced program are twice that of the A/C Cycling Base program. All programs require a minimum term of service of one year. All programs are currently open to new customers.

As of June 30, 2002, participation on the A/C Cycling Programs was as follows:

- A total of 102,930 residential customers were enrolled in the Residential Air Conditioner Cycling Base program representing a total potential net peak load reduction of 199.2 MW
- A total of 2,374 non-residential customers were enrolled in the Non-Residential Air Conditioner Cycling Base program representing a total potential net peak load reduction of 37.2 MW

- A total of 4,651 residential customers were enrolled in the Residential Air Conditioner Cycling Enhanced program representing a total potential net peak load reduction of 9.6 MW
- A total of 65 non-residential customers were enrolled in the Non-Residential Air Conditioner Cycling Enhanced program representing a total potential net peak load reduction of 1.3 MW

(8) Real Time Energy Metering

SCE's Real-Time Energy Metering ("RTEM") program is a result of a joint utility effort that was sponsored by the CEC and made possible by the California Legislature.[11] This effort involves the purchase and installation of advanced interval metering and related metering communication and end-user information/notification systems for all accounts with monthly maximum demands of 200 kW or more. Installation of such equipment and systems provides affected customers with access to their interval usage information via the Internet, which is updated on a daily basis. This should, in turn, allow such customers to effectively manage their loads in response to real-time pricing rates and demand responsiveness programs.

Operationalizing RTEM involves four primary components: (1) purchasing and installing interval meters equipped with two-way communication capabilities, which utilize paging, phone lines, or NetComm[12] as communication media, depending on pager coverage and availability of telephone service; (2) purchasing and installing servers, workstations and infrastructure to initiate, process and transfer daily/hourly meter reads via pager, telephone and Netcomm networks; (3)

---

[11] On April 11, 2001, Governor Davis signed into law Assembly Bill ("AB") X1 29, which appropriated $35 million in state funds for the CEC to further the installation of real time energy metering.

[12] SCE's wide-area communication infrastructure built for distribution system automation purposes

purchasing and installing application software to control the servers and interface with SCE's billing and customer usage systems; and (4) purchasing third-party software to provide a web-based customer interface tool that allows customers to access their usage via the Internet and allows SCE to track participation in curtailment programs.

Within SCE's service territory, there are approximately 11,000 accounts with demands that exceed 200 kW. Because some accounts require use of multiple meters, SCE estimates a total of 12,000 meters would qualify under this program. As of June 30, 2002, SCE has installed RTEM technology for over 9,000 accounts. SCE anticipates that the remaining eligible accounts will receive installation of RTEM technology systems by the end of 2002.

b) Pricing Options

The following is a brief description of the existing pricing options available to SCE's Large Customers.

(1) Real-Time Pricing Rate Schedules (RTP-2 and RTP-2-I)

SCE has two real-time pricing options for Large Commercial Customers under Rate Schedules RTP-2 and RTP-2-I that are applicable only to customers who have been taking service under these rate schedules prior to June 1996. These rate schedules were closed to new customers when the Power Exchange became operational.

SCE notes that these real time pricing options are not true "dynamic pricing" options because the hourly rates for the energy are based on the prior day's temperature rather than on real-time system conditions. Under these hourly pricing options, the energy prices are differentiated by type of day (weekday or weekend), season (summer and winter) and by temperature (extremely hot, very hot, hot, moderate and mild) as recorded by the National Weather Service at its Los Angeles Downtown site.

Rate schedule RTP-2-I was applicable to interruptible customers whose demands exceed 500 kW. Rate schedule RTP-2 was available to non-Interruptible customers whose demands exceed 500 kW. A contract was required for this service and customers were required to sign for 12 months of service under these rate schedules.

(2) Time-Of-Use Rate Schedules

For several decades, SCE has offered time-of-use ("TOU") rate schedules for Large Commercial and Industrial Customers. Such customers include large manufacturers and processors, supermarkets, colleges or universities, hospitals and office buildings. These rate schedules are mandatory for customers with monthly demands of 500 kW or greater. SCE offers the following TOU rate schedules for this customer group:

- TOU-8 – the basic, default time-of-use rate schedule for large commercial & industrial customers,
- TOU-PA's – time-of-use rate schedules for agricultural customers, and
- TOU-8-SOP, TOU-8-SOP-I, and TOU-PA-SOP – optional time-of-use rates for those large commercial, industrial and agricultural customers who use most or all of their usage during the super-off-peak time period

Under SCE's TOU rate schedules, the customer's unbundled energy charges are differentiated between on-peak, mid-peak, and off-peak periods with prices highest during the on-peak period and lowest in the off-peak period. In addition, SCE offers the TOU pricing with a "super off-peak" feature during certain off-peak periods with corresponding energy charges that are lower than the ordinary off-peak charge. The on-peak, mid-peak and off-peak charges are determined by the marginal costs SCE incurs to provide electric service during these time periods. The purpose of the TOU rates is to induce customers through price to shift their load consumption patterns to less expensive periods.

In addition to the TOU rate schedules offered to customers with demands of 500 kW or greater, the Commission recently adopted mandatory TOU pricing for customers with demands between 200 kW and 500 kW. All customers who have a Real-Time Energy Metering or other interval meter, whether provided under the provisions of ABX1 29 or otherwise, are to take service under Rate Schedules GS-2-TOU (for commercial and industrial customers) or TOU-PA (for agricultural customers). Additionally, customers with demands between 20 kW and 500 kW have the option to take service on Rate Schedule TOU-GS, an optional time-of-use schedule with more variation between on-peak mid-peak and off-peak rates than the rates associated with rate schedule GS-2-TOU.

As part of SCE's Phase 2 GRC, SCE is in the process of evaluating some of its time-of-use schedules, which were originally designed under a fully integrated utility model, to assess the cost-basis for these offerings under current market conditions.

Table III-2 below shows the number of Large Customers with demands exceeding 200 kW that are currently participating on either a Real-Time Pricing or Time-of-Use Rate Schedule.

Table III-2 – Number of Large Customers (>200 kW) by Rate Schedule

Rate Schedule	Number of Customers
RTP-2 & RTP-2-I	96
TOU-8	2,857
TOU-8-SOP, TOU-GS-SOP & TOU-PA-SOP	146

GS-2-TOU	5,492
TOU-GS	287
TOU-PA's	758
Total	9,636

2. Description of Demand Response Programs and Pricing Options Available to Smaller Commercial and Residential Customers

a) Demand Response Programs

SCE's existing demand response programs available to Smaller Commercial Customers include the DBP, SLRP, OBMC and A/C cycling programs discussed previously. In general, demand response programs for Residential Customers are limited to direct load control programs, which are described below:

(1) Demand Bidding Program

SCE offers its DBP to Small and Medium Commercial Customers with demands greater than 100kW. To avoid unnecessary duplication, the description of the DBP is provided in the discussion above concerning Large Customers.

(2) Scheduled Load Reduction Program

SCE offers its SLRP to Small and Medium Commercial Customers with demands greater than 100kW. To avoid unnecessary duplication, the description of the SLRP is provided in the discussion above concerning Large Customers.

(3) Optional Binding Mandatory Curtailment Program

OBMC is also available to Smaller Customers, but due to the relatively small size of these customers compared to typical circuit loads, this program is not available to the majority of Smaller Customers unless they are able to participate with other customers in aggregating their load reductions and submitting a plan together. To avoid unnecessary duplication, the description of the OBMC is provided in the discussion above concerning Large Customers.

(4) Residential and Non-Residential Air Conditioner Cycling Program (Base and Enhanced)

SCE offers a load control air conditioner cycling program available to all customer segments. To avoid unnecessary duplication, the description of the program is provided in the discussion above for Large Customers.

(5) Demand Response Pilot Program – AB970 Smart Thermostat

Pursuant to AB970 and D.01-03-073, SCE has been conducting a pilot program to test the viability of a new approach to small commercial load control and demand-responsiveness through the use of Internet technology and thermostats to affect HVAC energy use. The "Smart Thermostat" program is designed to include approximately 5,000 small commercial customers under 200 kW in SCE's service territory, representing an estimated 4 MWs in peak demand reduction. Customers participating in the program are provided with a new digital programmable thermostat (controlled by SCE) and a financial incentive ($300) for program participation.

Under this program, participating customers allow SCE to adjust their thermostat remotely to reduce their electrical demand from HVAC use, but customers still maintain some level of control and have the ability to override SCE's adjustment, with resulting financial penalties. SCE provides feedback to customers about their responsiveness and the financial impact of their decision whether to contribute to demand reduction or override SCE's adjustment.

SCE began offering this pilot to customers in the fall of 2001 and is currently in the process of signing up customers and installing thermostats, with the goal of reaching a fully subscribed pilot consisting of 5,000 devices. As of July 30, 2002, SCE has installed approximately 3,000 thermostats for customers who are currently enrolled in this program.

b) **Pricing Options**

SCE has offered its Medium and Small Commercial and Residential customers several TOU pricing options. Similar to the Large Customers' TOU options, the energy charge in these rate options are differentiated by on-peak and off-peak pricing periods. They are also differentiated by season (summer or winter). The following pricing options are available to these customer segments:

- TOU-GS-1 and TOU-GS-2 are time-of-use rate options available to medium and small commercial customers
- TOU-GS2-SOP is a time-of-use rate option available to medium and small commercial customers who use most or all of their usage during the super-off-peak time period
- TOU-EV3 is a time-of-use rate option available to customers with Electric Vehicles
- A wide variety of TOU-PA time-of-use rate options are available to medium and small agricultural customers
- TOU-D-1 or TOU-D-2 are time-of-use rate options available to residential customers

As part of SCE's Phase 2 GRC, SCE is in the process of evaluating some of its time-of-use schedules, which were originally designed under a fully integrated utility model, to assess the cost-basis for these offerings under current market conditions.

Table III-3 below provides the number of medium and small business and residential customers with demands less than 200 kW that are currently participating on an optional Time-of-Use Rate Schedule.

Table III-3 – Number of Medium and Small Business and Residential Customers (<200 kW) by Rate Schedule

Rate Schedule	Number of Customers
TOU-GS	4,459
TOU-GS-SOP & TOU-PA-SOP	985
TOU-EV	50
TOU-PA's	2,988
TOU-D-1 and TOU-D-2	4,107
Total	12,589

B. Description of SCE's Planned Efforts for Demand Response Programs and Pricing Options

SCE recognizes the importance of demand response efforts in reducing procurement costs and mitigating the potential for outages. Currently, SCE maintains a robust portfolio of demand response options for customers and is continuing to assess new and different ways to maximize program and pricing effectiveness. Towards this goal, SCE has the following planned efforts underway:

1. Planned Real Time Pricing Effort

In SCE's Real-Time Pricing ("RTP") Proposal,[13] SCE proposed a new RTP option for customers with interval meters. Such an option was based on a hybrid RTP/TOU rate that was included in a draft proposal submitted by San Diego Gas & Electric Company in their Rate Stabilization proceeding.[14] This hybrid rate option strikes a balance between the fundamental principles of real-time pricing and the concerns of all interested parties in expanding the use of RTP options in an uncertain wholesale energy market.

As SCE stated in its RTP proposal, SCE's proposed option would be a voluntary RTP option that would combine the TOU energy prices currently in effect with hourly-differentiated energy prices reflecting market conditions during critical periods. Under SCE's proposal, energy prices would transition from stable and predictable TOU prices in the off-peak and mid-peak hours to hourly RTP prices during the on-peak periods, or possibly other critical periods when wholesale energy prices are volatile and/or energy supplies are low. Hourly prices would be provided on a day-ahead basis and would not be subject to true-up after the fact, allowing customers to make consumption decisions based on the prices that would actually form the basis for their bill. TOU prices would apply to all hours in the applicable time periods and therefore form a stable price in all but those hours when market energy prices are most volatile.

SCE proposes that this new RTP schedule be included as one of the dynamic pricing options to be tested in the Large Customer pilot that SCE has proposed in

---

[13] At the Commission's direction, SCE submitted a Real Time Pricing Proposal to the Commission on August 17, 2001, in the A.00-11-038 rate stabilization proceeding.

[14] On July 23, 2002, the CPUC issued a draft resolution that proposes to adopt SDG&E's proposal on a pilot basis

this Rulemaking. Should the Commission adopt SCE's proposal that a pilot should be conducted and that SCE's RTP Proposal be tested as part of this pilot, this schedule would be available to customers whose demand exceed 200 kW and who have RTEM metering capabilities to support such a rate option.

In order to facilitate customer notification of real-time prices on a day-ahead basis, a mechanism will need to be put in place to deliver the day-ahead schedules to customers so that they can accordingly adjust their load in response to these prices. The existing web-based customer interface system used for RTEM could be enhanced to make it possible for customers to view day-ahead hourly price schedules associated with this tariff and to view graphs that chart historical usage and prices on an hourly basis. In addition to this enhancement, another enhancement that can be offered to participating customers is a cost analyst tool that allows customers to perform "what if" scenarios that will aid customers in making energy management decisions that consider the impact of these decisions on their bill.

2. Planned Critical Peak Pricing Efforts

In cooperation with the CEC, SCE has committed to test a Critical Peak Pricing ("CPP") rate option for a subset of the Smart Thermostat customers. Medium-size customers with Smart Thermostats will be offered a TOU-based CPP rate option as an added participant incentive for reducing their electricity costs. While the mid-peak and off-peak rates remain constant and set at reduced levels from existing rates, when system conditions warrant the activation of a "critical peak period," some or all of the on-peak rates would vary based on market conditions. During this pilot, customers will be notified of CPP periods where their on-peak rate is significantly higher than the base TOU on-peak rate. The demand responsive behavior from the customer is to avoid this CPP price schedule by reducing their electrical demand, thereby reducing their overall energy usage and cost. Metering will record usage, behavior changes, and load shifts.

This pilot is currently in the design stage, with a pilot tariff under design and customer market research in progress. SCE is also evaluating whether to test small commercial customer responsiveness and preferences. The pilot is expected to be fully subscribed by summer 2003. A summer impact report will be issued at the end of 2003.

3. Need for Transparent Market Pricing

Critical to developing any form of dynamic, market-based pricing is the availability of a viable mechanism to simulate market prices on which to base rates, given that current market prices are not readily available. SCE anticipates this to be one of the topics that will be discussed at upcoming workshops in this proceeding.

IV.

CONCLUSION

The information presented in this report demonstrates that for Large Customers, significant infrastructure and demand response programs already exist upon which further enhancements can be leveraged. The information also shows that opportunities are available to pursue development of preferred dynamic pricing options that would be ready for deployment as a pilot in late 2002 and possible full deployment by 2003. SCE believes that the most expedient way to develop and test preferred dynamic pricing options would be to first address key aspects of these options in a workshop setting.

In addition, the information presented in this report demonstrates that lower levels of meter and communications infrastructure, demand response programs and dynamic pricing options are available to Small and Medium Commercial and

Residential Customers as compared to Large Customers. In order to identify the appropriate level of infrastructure to support a preferred set of demand response programs and dynamic pricing options for these customers, workshops need to carefully consider the need for pilot programs to serve as a basis for demonstrating cost-effectiveness prior to instituting policies that would direct utilities to make large capital investments to deploy advanced metering or other substantial infrastructure.

Respectfully submitted,

MICHAEL D. MONTOYA
JENNIFER R. HASBROUCK

By: Jennifer Hasbrouck
Jennifer R. Hasbrouck

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1040
Facsimile: (626) 302-2050
E-mail: jennifer.hasbrouck@sce.com

Dated: August 9, 2002

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REPORT ON EXISTING AND PLANNED DEMAND RESPONSE AND PRICING OPTIONS** on all parties identified on the attached service list. Service was effected by means indicated below:

☑ Placing the copies in properly addressed sealed envelopes and depositing such envelopes in the United States mail with first-class postage prepaid (Via First Class Mail);

☐ Placing the copies in sealed envelopes and causing such envelopes to be delivered by hand to the offices of each addressee (Via Courier);

☑ Transmitting the copies via facsimile, modem, or other electronic means (Via Electronic Means).

Executed this **9th day of August, 2002**, at Rosemead, California.

M Rizvi

Meraj Rizvi
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.	R.02-06-001 (Filed June 6, 2002)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REPORT ON EXISTING AND PLANNED DEMAND RESPONSE AND PRICING OPTIONS

MICHAEL D. MONTOYA
JENNIFER R. HASBROUCK

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1040
Facsimile: (626) 302-2050
E-mail: jennifer.hasbrouck@sce.com

Dated: August 9, 2002

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.	R.02-06-001 (Filed June 6, 2002)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REPORT ON EXISTING AND PLANNED DEMAND RESPONSE AND PRICING OPTIONS

I.

INTRODUCTION

In accordance with the California Public Utilities Commission's ("Commission") directives as set forth in the Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing dated June 6, 2002 (the "OIR"), respondent Southern California Edison Company ("SCE") hereby submits this report describing SCE's existing and planned efforts concerning demand response and pricing efforts. As directed by the Commission in the OIR, this information is presented to help facilitate the Commission's investigation into where gaps may exist in the ongoing and planned efforts of the utilities and other agencies such as the California Energy Commission ("CEC") and the California Power Authority ("CPA").

II.

BACKGROUND

A. Purpose of this Report

In the OIR, the Commission cites its intention to consider a strategic approach towards the orderly development of demand responsiveness capability in the California electric market. Toward this end, the Commission has designed its preferred approach which involves conducting a review of existing and planned demand response efforts in California to identify gaps in current efforts and then initiating further discussion as to how such gaps might be filled in order to maximize demand response resources. To facilitate the Commission's investigation into identifying potential gaps, the Commission directed all the parties in this proceeding to submit a brief description of their existing and planned demand response and pricing programs.

This report provides a brief description of SCE's existing and planned efforts for its demand response programs and pricing options available for its large customers, medium and small business customers, and residential customers. This filing also identifies some issues that may be discussed in a workshop setting when considering options to address any potential gaps that may exist.

B. Background on the Focus of this Report

In the OIR, the Commission identified three categories of demand response efforts, including short-term emergency options, flexible dispatch options, and permanent options. The Commission stated that its intention in this Rulemaking will be to focus on demand response efforts that are considered to be "flexible and dispatchable" in nature. The Commission cited time-of-use ("TOU") pricing, real-time pricing, smart thermostats, demand bidding and energy management control systems as the types of efforts that are included within the scope of this proceeding. In its discussion of program strategies for customer demand reduction, the Commission categorized interruptible and direct load control programs as "emergency" strategies that are generally outside the scope of the proceeding.

Despite this initial attempt to narrow the scope of this proceeding, the OIR did cite to some existing programs, such as Santa Clara County's base interruptible program, as examples of existing programs that would be considered in its strategic approach, even though technically an interruptible program might be categorized as an "emergency" effort. In order to provide a comprehensive list of existing demand response efforts for the Commission's consideration, SCE is including information in this report on its "emergency" efforts (interruptible and direct load control programs) and its "flexible dispatch" efforts on both current and planned demand response programs, dynamic/TOU pricing, and supporting infrastructure. Providing information on these programs will also be useful to the Commission because they provide valuable information on customer response and acceptance of existing "emergency" programs. SCE believes that these programs need to be viewed along side "flexible dispatch" programs as an integrated portfolio of demand response program options that are available to customers. SCE's current demand response programs offer nearly 1,000 MW of curtailable load. Major energy efficiency initiatives and related programs are considered to be outside the scope of this proceeding.

III.

DESCRIPTION OF EXISTING AND PLANNED DEMAND RESPONSE AND PRICING PROGRAMS

In accordance with the directives set forth in the OIR, SCE provides a brief description of its existing and planned demand response programs and pricing options for large customers, medium and small business, and residential customers. For purposes of this report, SCE considers "Large Customers" to be accounts with registered demand equal to or in excess of 200 kW, although some programs may only be available to customers with demands of 500 kW or greater. Conversely, "Small or Medium Commercial Customers" are considered to be commercial customers with demands less than 200 kW.

The OIR asked specifically that for each existing or planned demand response or pricing effort identified, the parties provide the following information: (1) description of the target customer segment(s); (2) type of strategy; (3) parties involved; (4) hardware and/or software requirements; (5) resources delivered or planned; (6) cost; (7) funding source; and (8) status. This information is discussed in detail in this report, but is summarized in Table III-1 below:

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
Demand Bidding	Large Commercial & Industrial (>500 kW) Small & Medium Commercial (>100 kW)	Flexible	SCE, ISO	Internet Web Site Curtailment Event Management system (software) IDR	15.9 (min. bid) 212.0 (max. bid)	Incentive Admin/Opns Total	N/A	35 c/kWh $9 /kW NA	ILPMA ILPMA	Operational

---

1 Incentive costs for SCE's traditional interruptible programs (I-6, ACCP-Base and AP-I) are derived from 2001 actual payments to participants and estimated available interruptible loads during that period. ACCP-Enhanced incentives are twice those derived for ACCP-Base. BIP incentive is the monthly credit ($7/kW) annualized. I-6 incentives are adjusted to exclude the impact of a bill limiter rate subsidy. SLRP and DBP incentives reflect the tariff payment amount per kWh. Administration and operations costs for all interruptible programs are derived from 2002 booked amounts through June 30 and annualized.

2 Funding sources are as follows:

DSM C'over: D. 97-12-103 authorized SCE to use the DSM carryover balance from the DSM Balancing Account to fund pre-1998 commitments such as the I-6, ACCP-Base and AP-I load control programs, with the expectation that these programs would require funding only through March 31, 2002. However, D.01-04-006 extended the programs through 2002 and subsequently D.02-04-060 extended the programs through the conclusion of SCE's 2003 GRC. SCE expects to exhaust the Demand Side Management carryover funds in 2002. At that point SCE will record the administrative and operations cost of these programs in the ILPMA for the remainder of 2002. SCE has requested recovery of all program costs in base rates for 2003 and beyond in its 2003 GRC.

ILPMA: The Interruptible Load Program Memorandum Account was authorized by the Commission in D.01-04-006 to allow SCE to record the costs of new programs that exceed that authorized in base rates. SCE is allowed to recover these costs subject to a reasonableness review held in the Annual Earnings Assessment Proceeding.

Base Rates: Costs funded in base rates were authorized in the 1995 GRC. The incentives for the traditional interruptible programs as well as a portion of administrative and operations expenses of these programs are funded in base rates.

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
SLRP	Large Commercial & Industrial (>500 kW) Small & Medium Commercial (>100 kW)	Flexible	SCE	IDR	4.0	Incentive Admin/Opns Total	N/A	10¢/kWh $12/kW NA	ILPMA ILPMA	Operational
Interruptible Load Program (Schedule I-6)	Large Commercial & Industrial (>500 kW)	Emergency	SCE, ISO	Radio Comm. System; RTU and dedicated telephone at customer site; Auto. Notification System; IDR	591.0	Incentive Admin/Opns Total	N/A	$112 $ 2 $114	Base Rates DSM C'over	Operational (closed to new customers)
BIP	Large Commercial & Industrial (>500 kW)	Emergency	SCE, ISO	Dedicated telephone at customer site; IDR; Auto notification system	27.0	Incentive Admin/Opns Total	N/A	$84 $ 7 $91	ILPMA ILPMA	Operational
OBMC	Large Commercial & Industrial (>500 kW)	Emergency	SCE, ISO	Automated Notification System; IDR; Circuit Metering (if necessary)	9.3 (5%) 18.5(10%) 27.8(15%)	Incentive Admin/Opns Total	N/A	$ 0 $16* $16 *based on 5% level	ILPMA ILPMA	Operational
AP-I	Agriculture & Pumping	Emergency	SCE, ISO	Radio comm. system; Load Control device at customer site; Auto-notification system	25.5 (on-peak) 41.5 (off-peak)	Incentive Admin/Opns Total	N/A	$50 $ 4 $54	Base Rates DSM C'over	Operational

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
A/C Cycling-Base Program	Large Commercial & Industrial (>500 kW) Small & Medium Commercial (<500 kW)	Emergency	SCE, ISO	Radio comm. system; Load control device at customer site	37.2	Incentive Admin/Opns Total Load Control Device&Instal	N/A $153	$52 $ 3 $55 -	Base Rates DSM C'over DSM C'over	Operational

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
A/C Cycling: Enhanced Program	Large Commercial & Industrial (>500 kW) Small & Medium Commercial (<500 kW)	Emergency	SCE, ISO	Radio comm. System; Load Control device at customer site	1.3	Incentive Admin/Opns Total Load Control Device&Instal	N/A $153	$104 $ 3 $107 -	ILPMA ILPMA ILMPA	Operational
RTEM	Large Commercial & Industrial (>200 kW)	TOU Pricing (Infrastruc ture)	SCE, CEC	IDR Meter with pulse board, Various Meter Communications Devices Include: Two-way Pager, Internal Phone Modem or RS232 Board for use with Netcomm Wireless System Software Applications: M32 & MV-90 Web-Based Customer Interface Communication System	N/A	(Annual $000) One-Time Costs: Meter Hardware Comm. Sys. Meter Installation Customer Data Comm. End-User Education Total One-Time Costs Total 2001 Ongoing Costs Total 2002 Ongoing Costs		($000) $11,937 $2,737 $3,139 $8,234 $446 $26,493 $4,873 $4,368	ABX 1-29 & SBX 1-5; RTEM Memo Account[3]	Operational

3 ABX1 29 and SBX1 5 authorized funding by the CEC to the utilities for real-time meters and related infrastructure. The RTEM Memorandum Account tracks incremental costs associated with installation and operation of RTEM equipment that exceeds funding by the CEC.

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
Rate Schedules: RTP-2 RTP-2-1 TOU-8 TOU-PA's TOU-8-SOP TOU-8-SOP-I TOU-PA-SOP TOU-GS GS-2-TOU	Large Commercial (>200 kW)	Pricing Options	SCE	IDR Meter	N/A	N/A	N/A	N/A	Base Rates	Operational
A/C Cycling: Base Program	Residential	Emergency	SCE, ISO	Radio comm. System; Load control device at customer site	199.2	Incentive Admin/Opns Total Load Control Device&Instal	N/A $153	$50 $ 3 $53 -	Base Rates DSM C'over DSM C'over	Operational

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
A/C Cycling: Enhanced Program	Residential	Emergency	SCE, ISO	Radio comm. System; Load control device at customer site	9.6	Incentive Admin/Opns Total Load Control Device&Instal	N/A $153	$100 $ 3 $103 -	ILPMA ILPMA ILPMA	Operational
Smart Thermostat Pilot	Small Commercial (>200kW)	Flexible	SCE, CEC	Programmable thermostat; Internet Website; 2-way pager communications	4.0 (at full build-out)	Incentive Auth.Annual Budget[4]	$300 $5.94 million	NA	Demand Reduction & Self-Gen. Incremental Costs Balancing Account [5]	Operational
Rate Schedules: TOU-GS TOU-GS-SOP TOU-PA-SOP TOU-EV TOU-PA's TOU-D1 TOU-D2	Small Commercial (<200 kW) Residential	Pricing Options	SCE	TOU Meter	N/A	N/A	N/A	N/A	Base Rates	Operational

---

4 Smart Thermostat pilot was authorized in D.01-03-073, with an annual budget of $5,940,000, consisting of $1,188,000 for contract administration, marketing, regulatory reporting and program evaluation and $4,752,000 for hardware, software, communications, and customer incentives.

5 The Demand Reduction and Self-Generation Incremental Costs Balancing Account records incremental costs and benefits associated with the Smart Thermostat Pilot Program and the Self-Generation Pilot Program. Disposition of amounts recorded will be determined in the annual Revenue Adjustment Proceeding or other proceeding authorized by the Commission.

Table III-1
Summary of SCE's Existing and Planned Programs

Program Description	Target Customer Segment	Type of Strategy	Parties Involved	Hardware/ Software Requirements	Resources Delivered/ Planned MWs as of 6/30/02	Cost per Year[1]			Funding Source[2]	Status
						Description	$/meter	$/kW		
Rate Schedule RTP/TOU	Large Commercial (>200 kW)	Pricing Option	SCE	RTEM Infrastructure	N/A	N/A	N/A	N/A	N/A	Planned
Critical Peak Pricing Pilot	Small Commercial (<200kW)	Pricing Pilot	SCE, CEC	IDR Smart Thermostat Customer Notification system	N/A	N/A	N/A	N/A	N/A	Planned

A. Description of SCE's Existing Efforts for Demand Response Programs and Pricing Options

1. Description of Existing Demand Response Programs and Pricing Options Available to Large Customers

a) Demand Response Programs

SCE offers a number of existing demand response pricing, programs and infrastructure available to Large Customers, including the following:

(1) Demand Bidding Program

The Demand Bidding Program ("DBP") is a reliability-based demand-response program that offers customers a payment or credit on their bill when they curtail load at critical times as determined by the California Independent System Operator ("ISO").[6] During such critical times, a customer may bid for specified load reductions in exchange for being paid $0.35 per kWh if the bid is accepted and executed.[7] Customers may submit bids between 8:00 a.m. and 8:00 p.m. on weekdays. Participants must submit bids to reduce load for at least two consecutive hours, but may vary the size of the bid by hour. There are no penalties associated

---

[6] On July 17, 2002, in D.02-07-035, the Commission modified the terms of the DBP, transforming the DPB from a price mitigation program triggered by the California Department of Water Resources to a reliability program triggered by the ISO. The ISO will trigger a day-ahead DBP event when system reserves are anticipated to fall below 7% in the next 24 hours. The ISO may also trigger a day-of event when system operating reserves are forecast at 7% or below on an hour-ahead basis. The ISO may determine the length of the DBP event and limit the total amount of load reduction requested.

[7] The amount of a participant's load reduction is determined by comparing the hourly demands to the corresponding 10-day rolling average demand.

with this program.[8] DBP participants may be enrolled in other demand response programs such as I-6, BIP or ACCP, but they will not receive any payments for DBP during periods when load reductions under the other programs are in effect.

Since this program's recent redesign from a market-driven to a reliability-based program, the ISO has not yet triggered an event. Thus, at this time, SCE has no actual performance data from which to make meaningful estimates of projected load reductions. The DBP is available to all customers whose demand is equal to or greater than 100 kW.

As of June 30, 2002, SCE has enrolled 98 customers with a total of 135 service accounts. The maximum potential bid amount is 212 MW, while the minimum potential bid amount, assuming all customers bid their minimum requirement under the terms of the program, is 16 MW.

SCE utilizes an Internet-based application that leverages SCE's RTEM infrastructure (see description of RTEM below) for the Demand Bidding Program's customer notification, bidding, and operations. The Internet-based application, designated "SCE Curtailment Manager," is currently available only to DBP participants; however, SCE plans to extend certain capabilities of the application to other demand response programs, as appropriate.

SCE Curtailment Manager supports program participants as well as SCE's program operations and delivery. For program participants, the application provides notice of activated curtailment events, presents program information and incentives as well as historical, rolling averages, and target loads. It also provides the interface for program participants to submit curtailment bids as well as to

---

[8] Non-compliance on three consecutive occasions will result in the participant being excluded from bidding for the subsequent two DBP events.

monitor performance in near real time. Finally, it provides program participants with their estimated earned incentive. For SCE, the application allows rapid deployment of new or revised curtailment programs and complete program operations support, including event and customer performance reporting.

(2) Scheduled Load Reduction Program

SCE's Scheduled Load Reduction Program ("SLRP") is a load reduction program that was mandated by the California State Legislature in Senate Bill X1 5. SLRP is exclusively a summer program, effective only from June 1 through September 30. Participating SCE customers receive a payment in the form of a bill credit of $0.10 per kWh when they agree to curtail load at pre-scheduled time periods. This program is available to SCE customers with demands of 100 kW and above. A participating customer may choose up to three of the following time periods a week during which they will curtail their usage: 8:00 a.m. to 12:00 p.m.; 12:00 p.m. to 4:00 p.m.; and 4:00 p.m. to 8:00 p.m. The customer may not choose the same time period more than twice a week. The SLRP program is in effect Monday through Friday, excluding holidays. There are no penalties associated with this program.[9]

As of June 30, 2002, SCE has enrolled 17 participants. Currently the maximum load reduction scheduled is 4.0 MW for most of the allowed hours on Mondays. On Fridays, the scheduled load reduction is on average about 1.5 MWs. For the balance of the weekdays, the load reductions range from zero (for eight hours) to 230 kW. For most of the week, current SLRP participants do not offer the ISO significant load curtailment capabilities when it may actually be needed to

---

[9] If a customer fails to curtail usage five times, the customer will be removed from the program.

maintain system reliability during an emergency. In SCE's Phase 2 General Rate Case ("GRC"), SCE is considering a proposal to terminate the SLRP.

(3) Commercial Interruptible Load Program

The I-6 Interruptible Load Program is available to Large Commercial and Industrial Customers whose demand exceeds 500 kW and who agree to curtail their electric demand during a system capacity shortage or other emergency.

Under the program, a participating customer receives a discounted demand and energy rate for reducing load when requested by SCE. The discounted demand rate is applied to the amount of interruptible load contributed by the customer, which is defined by the excess of the customer's measured demand over its Firm Service Level ("FSL").[10] The discounted energy rate is applied to the kWhs that exceed what the customer would consume at its FSL over the time period to which the energy rate applies. The demand and energy discounts are generally greatest during the summer months.

A customer is called upon to reduce load to its FSL when SCE is notified by the ISO that a Stage 2 emergency exists and that non-firm load reductions are required. SCE then notifies the customer, who has thirty minutes to reduce the customer's load to the FSL. Customers may be asked to reduce load for a period not to exceed six hours per event, with a maximum of four events per calendar week, 40 hours per month, and 150 hours or 25 events per year. Customers may increase or decrease their FSL, or elect to terminate participation in the program during an annual 30-day window, beginning November 1 of each year.

---

[10] The FSL is that level of demand that the customer agrees not to exceed during an interruptible event.

For each period of interruption during which the customer fails to interrupt (and hence consumes energy in excess of the customer's FSL), an applicable excess energy charge is added to the customer's bill based on the amount of excess energy used. Excess energy is the number of kWhs consumed during each period of interruption that exceed the product of the firm service level kW multiplied by the total number of hours of interruptions within the time period.

Customers are notified of an interruption through the use of a Remote Terminal Unit ("RTU") and/or back-up automated telephone communications. The RTU initiates an alarm at the customer's site to indicate that the emergency is in effect and that the participant has thirty minutes to reduce load. If the dedicated back-up telephone system is used, the customer is notified via telephone of the emergency and likewise has thirty minutes to reduce load. The participant may also connect load-shedding equipment to the RTU to automatically open circuits to the customer's equipment.

As of June 30, 2002, 571 service accounts are enrolled in the I-6 program, with a load reduction potential of approximately 591 MWs. The tariffs governing the program have been closed to new customers, with the exception of customers new to SCE's service territory and to existing customers adding new load since November 26, 1996. In SCE's Phase 2 GRC, SCE will be proposing to terminate the I-6 program and transfer participating customers to its Base Interruptible Program, described below.

(4) Base Interruptible Program

Like the I-6 program, the Commission-mandated Base Interruptible Program ("BIP") is a discounted rate option available to customers with maximum demand of 500 KW or greater who agree to curtail their electric demand during a system capacity shortage or other emergency. However, unlike the I-6 program, which has no minimum load reduction requirements, BIP participants must be able to reduce load by at least 15% of their annual maximum demand or a minimum of 100 kW. BIP is currently open to all eligible customers. In its Phase 2 GRC, SCE will be proposing to modify the eligibility requirements so that customers with maximum demands as low as 200 kW may participate in BIP.

A customer participating in the BIP program is paid a reservation fee for demand that it agrees to reduce when requested by SCE. The reservation fee is in the form of a bill credit applied only to the demand component of the interruptible load. Interruptible demand for rate discounting is the excess of the customer's average peak-period (mid-peak during the winter season) demand over its FSL.

A BIP participant is called upon to reduce load to its FSL when SCE is notified by the ISO that a Stage 2 emergency exists and that non-firm load reductions are required. BIP participants are notified by telephone through an automated notification system. As is the case for I-6 participants, a BIP participant has thirty minutes from notification to reduce load to its FSL.

The number and frequency of times that SCE may ask a BIP participant to reduce load are slightly lower than those required for the I-6 program. BIP participants may be asked to reduce load for a period not to exceed four hours per event per day, with a maximum of 10 events per month or 120 hours per year. Customers may increase or decrease their FSL, or elect to terminate participation in the program during an annual 30-day window, beginning November 1 of each year, subject to the normal tariff restrictions requiring customers to remain on a rate for 12 months. As is the case with participants in the I-6 program, a BIP participant is also subject to penalties for not reducing load when requested to do so.

As of June 30, 2002 there are 36 participants in BIP with an estimated interruptible load of 27 MWs.

(5) Optional Binding Mandatory Curtailment Program

The Optional Binding Mandatory Curtailment ("OBMC") program exempts customers from rotating outages in exchange for partial load curtailment of their entire circuit during every rotating outage. Customers are required to file an OBMC plan that is acceptable to SCE prior to participation in the program. Customers are responsible for the installation and cost of communications and metering equipment required to participate in the program.

To participate, a minimum of 15 percent of the entire circuit load must be available for curtailment during every rotating outage. If any one customer does not have enough curtailable load to provide the 15 percent minimum requirement on their own, customers on the same circuit may submit one OBMC plan outlining how they can provide the 15 percent minimum requirement by combining total curtailable circuit load. OBMC customers are eligible to participate in other capacity interruptible programs, such as the interruptible I-6 program and the BIP program, subject to certain restrictions, as well as the DBP. Customers who fail to reduce load when requested are subject to penalties.

Since the program's inception, no OBMC events have occurred. As of June 30, 2002, there are 14 OBMC customer plans in effect, with a circuit load of 27.8 MW at the 15% curtailment level.

(6) Agricultural and Pumping Interruptible Program

The Agricultural and Pumping Interruptible Program ("AP-I") is applicable to those customers served under an Agricultural and Pumping rate schedule that elect to provide interruptible load automatically. Qualifying customers must have a measured demand of 50 kW or greater, or a connected load of 50 horsepower or greater. The customer's interruptible load is the total load served under the regularly applicable rate schedule. No firm service level applies. This program is currently open to new customers, but it may not be available in certain areas where communication-signaling equipment has not been installed or signal strength is inadequate to activate or deactivate an interruption.

Load is controlled through a VHF-FM radio-controlled switch. These devices are one-way receivers that provide no signal receipt verification. An end-of-interruptible-period signal is transmitted to the control device and customers must manually restart electrical equipment at the end of the interruptible period. Some customers have requested and paid for remote interruption signal monitors to know when an interruption occurs, and when they may restart their pump motors. Other customers without a remote monitor must periodically inspect their equipment in the field.

Upon receipt of an ISO Stage 2 emergency declaration, SCE may activate the AP-I program. To join the program, customers pay a one-time charge for the cost of the control and monitoring equipment. AP-I customers receive a discounted rate for agreeing to reduce load when requested by SCE.

Customers may elect to terminate participation in the AP-I program during an annual 30-day window, beginning November 1 of each year. As of June 30, 2002, a total of 375 customers are enrolled in this program, representing a potential net peak load reduction of 26 MWs.

(7) Air Conditioner Cycling Program (Base and Enhanced)

SCE offers both Residential and Non-Residential Base and Enhanced Air Conditioner Cycling ("A/C Cycling") programs to all customer segments. The A/C Cycling programs are applicable to customers serviced under either SCE's Residential or General Service rate schedules. Under the provisions of these programs, customers agree to installation of an automatic control device that is installed, operated, and maintained by SCE at the customer's premises. The device is radio controlled and can cycle a customer's air conditioner off and on. SCE activates the cycling signals when directed by the ISO to curtail specific amounts of load. The A/C Cycling Program utilizes the same communications system, including transmitters and towers that are used for the I-6 and AP-I programs.

Participants may select an air conditioner cycling strategy to determine the percentage of time that the air conditioner is disconnected during an interruptible period. The cycling strategy options for residential customers are 50%, 67% or 100%. The cycling strategy options for non-residential customers are 30%, 40%, 50% or 100%. A participant may change to a lower cycling strategy at no charge during its first 12 months participation in an A/C Cycling program, and at a cost of $30 thereafter.

The A/C Cycling Base program is limited to 15 cycling periods per year. Under the A/C Cycling Enhanced Program, there is no limit to the number of interruptions that may occur. The interruption duration per occurrence for all A/C Cycling programs are limited to no more than six hours at a time. Interruption periods may occur during the summer season beginning at 12:00 a.m. on the first Sunday in June, and ending at 12:00 a.m. on the first Sunday in October. Participating A/C Cycling customers receive credits on their bill during the summer season months regardless of whether A/C cycling occurred. The credits for the A/C Cycling Enhanced program are twice that of the A/C Cycling Base program. All programs require a minimum term of service of one year. All programs are currently open to new customers.

As of June 30, 2002, participation on the A/C Cycling Programs was as follows:

- A total of 102,930 residential customers were enrolled in the Residential Air Conditioner Cycling Base program representing a total potential net peak load reduction of 199.2 MW
- A total of 2,374 non-residential customers were enrolled in the Non-Residential Air Conditioner Cycling Base program representing a total potential net peak load reduction of 37.2 MW

- A total of 4,651 residential customers were enrolled in the Residential Air Conditioner Cycling Enhanced program representing a total potential net peak load reduction of 9.6 MW
- A total of 65 non-residential customers were enrolled in the Non-Residential Air Conditioner Cycling Enhanced program representing a total potential net peak load reduction of 1.3 MW

(8) Real Time Energy Metering

SCE's Real-Time Energy Metering ("RTEM") program is a result of a joint utility effort that was sponsored by the CEC and made possible by the California Legislature.[11] This effort involves the purchase and installation of advanced interval metering and related metering communication and end-user information/notification systems for all accounts with monthly maximum demands of 200 kW or more. Installation of such equipment and systems provides affected customers with access to their interval usage information via the Internet, which is updated on a daily basis. This should, in turn, allow such customers to effectively manage their loads in response to real-time pricing rates and demand responsiveness programs.

Operationalizing RTEM involves four primary components: (1) purchasing and installing interval meters equipped with two-way communication capabilities, which utilize paging, phone lines, or NetComm[12] as communication media, depending on pager coverage and availability of telephone service; (2) purchasing and installing servers, workstations and infrastructure to initiate, process and transfer daily/hourly meter reads via pager, telephone and Netcomm networks; (3)

---

[11] On April 11, 2001, Governor Davis signed into law Assembly Bill ("AB") X1 29, which appropriated $35 million in state funds for the CEC to further the installation of real time energy metering.

[12] SCE's wide-area communication infrastructure built for distribution system automation purposes

purchasing and installing application software to control the servers and interface with SCE's billing and customer usage systems; and (4) purchasing third-party software to provide a web-based customer interface tool that allows customers to access their usage via the Internet and allows SCE to track participation in curtailment programs.

Within SCE's service territory, there are approximately 11,000 accounts with demands that exceed 200 kW. Because some accounts require use of multiple meters, SCE estimates a total of 12,000 meters would qualify under this program. As of June 30, 2002, SCE has installed RTEM technology for over 9,000 accounts. SCE anticipates that the remaining eligible accounts will receive installation of RTEM technology systems by the end of 2002.

b) <u>Pricing Options</u>

The following is a brief description of the existing pricing options available to SCE's Large Customers.

(1) <u>Real-Time Pricing Rate Schedules (RTP-2 and RTP-2-I)</u>

SCE has two real-time pricing options for Large Commercial Customers under Rate Schedules RTP-2 and RTP-2-I that are applicable only to customers who have been taking service under these rate schedules prior to June 1996. These rate schedules were closed to new customers when the Power Exchange became operational.

SCE notes that these real time pricing options are not true "dynamic pricing" options because the hourly rates for the energy are based on the prior day's temperature rather than on real-time system conditions. Under these hourly pricing options, the energy prices are differentiated by type of day (weekday or weekend), season (summer and winter) and by temperature (extremely hot, very hot, hot, moderate and mild) as recorded by the National Weather Service at its Los Angeles Downtown site.

Rate schedule RTP-2-I was applicable to interruptible customers whose demands exceed 500 kW. Rate schedule RTP-2 was available to non-Interruptible customers whose demands exceed 500 kW. A contract was required for this service and customers were required to sign for 12 months of service under these rate schedules.

(2) Time-Of-Use Rate Schedules

For several decades, SCE has offered time-of-use ("TOU") rate schedules for Large Commercial and Industrial Customers. Such customers include large manufacturers and processors, supermarkets, colleges or universities, hospitals and office buildings. These rate schedules are mandatory for customers with monthly demands of 500 kW or greater. SCE offers the following TOU rate schedules for this customer group:

- TOU-8 – the basic, default time-of-use rate schedule for large commercial & industrial customers,
- TOU-PA's – time-of-use rate schedules for agricultural customers, and
- TOU-8-SOP, TOU-8-SOP-I, and TOU-PA-SOP – optional time-of-use rates for those large commercial, industrial and agricultural customers who use most or all of their usage during the super-off-peak time period

Under SCE's TOU rate schedules, the customer's unbundled energy charges are differentiated between on-peak, mid-peak, and off-peak periods with prices highest during the on-peak period and lowest in the off-peak period. In addition, SCE offers the TOU pricing with a "super off-peak" feature during certain off-peak periods with corresponding energy charges that are lower than the ordinary off-peak charge. The on-peak, mid-peak and off-peak charges are determined by the marginal costs SCE incurs to provide electric service during these time periods. The purpose of the TOU rates is to induce customers through price to shift their load consumption patterns to less expensive periods.

In addition to the TOU rate schedules offered to customers with demands of 500 kW or greater, the Commission recently adopted mandatory TOU pricing for customers with demands between 200 kW and 500 kW. All customers who have a Real-Time Energy Metering or other interval meter, whether provided under the provisions of ABX1 29 or otherwise, are to take service under Rate Schedules GS-2-TOU (for commercial and industrial customers) or TOU-PA (for agricultural customers). Additionally, customers with demands between 20 kW and 500 kW have the option to take service on Rate Schedule TOU-GS, an optional time-of-use schedule with more variation between on-peak mid-peak and off-peak rates than the rates associated with rate schedule GS-2-TOU.

As part of SCE's Phase 2 GRC, SCE is in the process of evaluating some of its time-of-use schedules, which were originally designed under a fully integrated utility model, to assess the cost-basis for these offerings under current market conditions.

Table III-2 below shows the number of Large Customers with demands exceeding 200 kW that are currently participating on either a Real-Time Pricing or Time-of-Use Rate Schedule.

Table III-2 – Number of Large Customers (>200 kW) by Rate Schedule

Rate Schedule	Number of Customers
RTP-2 & RTP-2-I	96
TOU-8	2,857
TOU-8-SOP, TOU-GS-SOP & TOU-PA-SOP	146

GS-2-TOU	5,492
TOU-GS	287
TOU-PA's	758
Total	9,636

2. Description of Demand Response Programs and Pricing Options Available to Smaller Commercial and Residential Customers

a) Demand Response Programs

SCE's existing demand response programs available to Smaller Commercial Customers include the DBP, SLRP, OBMC and A/C cycling programs discussed previously. In general, demand response programs for Residential Customers are limited to direct load control programs, which are described below:

(1) Demand Bidding Program

SCE offers its DBP to Small and Medium Commercial Customers with demands greater than 100kW. To avoid unnecessary duplication, the description of the DBP is provided in the discussion above concerning Large Customers.

(2) Scheduled Load Reduction Program

SCE offers its SLRP to Small and Medium Commercial Customers with demands greater than 100kW. To avoid unnecessary duplication, the description of the SLRP is provided in the discussion above concerning Large Customers.

(3) Optional Binding Mandatory Curtailment Program

OBMC is also available to Smaller Customers, but due to the relatively small size of these customers compared to typical circuit loads, this program is not available to the majority of Smaller Customers unless they are able to participate with other customers in aggregating their load reductions and submitting a plan together. To avoid unnecessary duplication, the description of the OBMC is provided in the discussion above concerning Large Customers.

(4) Residential and Non-Residential Air Conditioner Cycling Program (Base and Enhanced)

SCE offers a load control air conditioner cycling program available to all customer segments. To avoid unnecessary duplication, the description of the program is provided in the discussion above for Large Customers.

(5) Demand Response Pilot Program – AB970 Smart Thermostat

Pursuant to AB970 and D.01-03-073, SCE has been conducting a pilot program to test the viability of a new approach to small commercial load control and demand-responsiveness through the use of Internet technology and thermostats to affect HVAC energy use. The "Smart Thermostat" program is designed to include approximately 5,000 small commercial customers under 200 kW in SCE's service territory, representing an estimated 4 MWs in peak demand reduction. Customers participating in the program are provided with a new digital programmable thermostat (controlled by SCE) and a financial incentive ($300) for program participation.

Under this program, participating customers allow SCE to adjust their thermostat remotely to reduce their electrical demand from HVAC use, but customers still maintain some level of control and have the ability to override SCE's adjustment, with resulting financial penalties. SCE provides feedback to customers about their responsiveness and the financial impact of their decision whether to contribute to demand reduction or override SCE's adjustment.

SCE began offering this pilot to customers in the fall of 2001 and is currently in the process of signing up customers and installing thermostats, with the goal of reaching a fully subscribed pilot consisting of 5,000 devices. As of July 30, 2002, SCE has installed approximately 3,000 thermostats for customers who are currently enrolled in this program.

b) **Pricing Options**

SCE has offered its Medium and Small Commercial and Residential customers several TOU pricing options. Similar to the Large Customers' TOU options, the energy charge in these rate options are differentiated by on-peak and off-peak pricing periods. They are also differentiated by season (summer or winter). The following pricing options are available to these customer segments:

- TOU-GS-1 and TOU-GS-2 are time-of-use rate options available to medium and small commercial customers
- TOU-GS2-SOP is a time-of-use rate option available to medium and small commercial customers who use most or all of their usage during the super-off-peak time period
- TOU-EV3 is a time-of-use rate option available to customers with Electric Vehicles
- A wide variety of TOU-PA time-of-use rate options are available to medium and small agricultural customers
- TOU-D-1 or TOU-D-2 are time-of-use rate options available to residential customers

As part of SCE's Phase 2 GRC, SCE is in the process of evaluating some of its time-of-use schedules, which were originally designed under a fully integrated utility model, to assess the cost-basis for these offerings under current market conditions.

Table III-3 below provides the number of medium and small business and residential customers with demands less than 200 kW that are currently participating on an optional Time-of-Use Rate Schedule.

Table III-3 – Number of Medium and Small Business and Residential Customers (<200 kW) by Rate Schedule

Rate Schedule	Number of Customers
TOU-GS	4,459
TOU-GS-SOP & TOU-PA-SOP	985
TOU-EV	50
TOU-PA's	2,988
TOU-D-1 and TOU-D-2	4,107
Total	12,589

B. Description of SCE's Planned Efforts for Demand Response Programs and Pricing Options

SCE recognizes the importance of demand response efforts in reducing procurement costs and mitigating the potential for outages. Currently, SCE maintains a robust portfolio of demand response options for customers and is continuing to assess new and different ways to maximize program and pricing effectiveness. Towards this goal, SCE has the following planned efforts underway:

1. **Planned Real Time Pricing Effort**

In SCE's Real-Time Pricing ("RTP") Proposal,[13] SCE proposed a new RTP option for customers with interval meters. Such an option was based on a hybrid RTP/TOU rate that was included in a draft proposal submitted by San Diego Gas & Electric Company in their Rate Stabilization proceeding.[14] This hybrid rate option strikes a balance between the fundamental principles of real-time pricing and the concerns of all interested parties in expanding the use of RTP options in an uncertain wholesale energy market.

As SCE stated in its RTP proposal, SCE's proposed option would be a voluntary RTP option that would combine the TOU energy prices currently in effect with hourly-differentiated energy prices reflecting market conditions during critical periods. Under SCE's proposal, energy prices would transition from stable and predictable TOU prices in the off-peak and mid-peak hours to hourly RTP prices during the on-peak periods, or possibly other critical periods when wholesale energy prices are volatile and/or energy supplies are low. Hourly prices would be provided on a day-ahead basis and would not be subject to true-up after the fact, allowing customers to make consumption decisions based on the prices that would actually form the basis for their bill. TOU prices would apply to all hours in the applicable time periods and therefore form a stable price in all but those hours when market energy prices are most volatile.

SCE proposes that this new RTP schedule be included as one of the dynamic pricing options to be tested in the Large Customer pilot that SCE has proposed in

---

[13] At the Commission's direction, SCE submitted a Real Time Pricing Proposal to the Commission on August 17, 2001, in the A.00-11-038 rate stabilization proceeding.

[14] On July 23, 2002, the CPUC issued a draft resolution that proposes to adopt SDG&E's proposal on a pilot basis

this Rulemaking. Should the Commission adopt SCE's proposal that a pilot should be conducted and that SCE's RTP Proposal be tested as part of this pilot, this schedule would be available to customers whose demand exceed 200 kW and who have RTEM metering capabilities to support such a rate option.

In order to facilitate customer notification of real-time prices on a day-ahead basis, a mechanism will need to be put in place to deliver the day-ahead schedules to customers so that they can accordingly adjust their load in response to these prices. The existing web-based customer interface system used for RTEM could be enhanced to make it possible for customers to view day-ahead hourly price schedules associated with this tariff and to view graphs that chart historical usage and prices on an hourly basis. In addition to this enhancement, another enhancement that can be offered to participating customers is a cost analyst tool that allows customers to perform "what if" scenarios that will aid customers in making energy management decisions that consider the impact of these decisions on their bill.

2. Planned Critical Peak Pricing Efforts

In cooperation with the CEC, SCE has committed to test a Critical Peak Pricing ("CPP") rate option for a subset of the Smart Thermostat customers. Medium-size customers with Smart Thermostats will be offered a TOU-based CPP rate option as an added participant incentive for reducing their electricity costs. While the mid-peak and off-peak rates remain constant and set at reduced levels from existing rates, when system conditions warrant the activation of a "critical peak period," some or all of the on-peak rates would vary based on market conditions. During this pilot, customers will be notified of CPP periods where their on-peak rate is significantly higher than the base TOU on-peak rate. The demand responsive behavior from the customer is to avoid this CPP price schedule by reducing their electrical demand, thereby reducing their overall energy usage and cost. Metering will record usage, behavior changes, and load shifts.

This pilot is currently in the design stage, with a pilot tariff under design and customer market research in progress. SCE is also evaluating whether to test small commercial customer responsiveness and preferences. The pilot is expected to be fully subscribed by summer 2003. A summer impact report will be issued at the end of 2003.

3. Need for Transparent Market Pricing

Critical to developing any form of dynamic, market-based pricing is the availability of a viable mechanism to simulate market prices on which to base rates, given that current market prices are not readily available. SCE anticipates this to be one of the topics that will be discussed at upcoming workshops in this proceeding.

IV.

CONCLUSION

The information presented in this report demonstrates that for Large Customers, significant infrastructure and demand response programs already exist upon which further enhancements can be leveraged. The information also shows that opportunities are available to pursue development of preferred dynamic pricing options that would be ready for deployment as a pilot in late 2002 and possible full deployment by 2003. SCE believes that the most expedient way to develop and test preferred dynamic pricing options would be to first address key aspects of these options in a workshop setting.

In addition, the information presented in this report demonstrates that lower levels of meter and communications infrastructure, demand response programs and dynamic pricing options are available to Small and Medium Commercial and

Residential Customers as compared to Large Customers. In order to identify the appropriate level of infrastructure to support a preferred set of demand response programs and dynamic pricing options for these customers, workshops need to carefully consider the need for pilot programs to serve as a basis for demonstrating cost-effectiveness prior to instituting policies that would direct utilities to make large capital investments to deploy advanced metering or other substantial infrastructure.

Respectfully submitted,

MICHAEL D. MONTOYA
JENNIFER R. HASBROUCK

By: Jennifer Hasbrouck
Jennifer R. Hasbrouck

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-1040
Facsimile: (626) 302-2050
E-mail: jennifer.hasbrouck@sce.com

Dated: August 9, 2002

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) REPORT ON EXISTING AND PLANNED DEMAND RESPONSE AND PRICING OPTIONS** on all parties identified on the attached service list. Service was effected by means indicated below:

☑ Placing the copies in properly addressed sealed envelopes and depositing such envelopes in the United States mail with first-class postage prepaid (Via First Class Mail);

☐ Placing the copies in sealed envelopes and causing such envelopes to be delivered by hand to the offices of each addressee (Via Courier);

☑ Transmitting the copies via facsimile, modem, or other electronic means (Via Electronic Means).

Executed this **9th day of August, 2002**, at Rosemead, California.

MRizvi

Meraj Rizvi
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770